November 15, 2004

Mr. Carlito Caliboso, Chairman
Hawaii Public Utility Commission
Department of Budget and Finance
465 S. King Street #103
Honolulu, Hawaii 96813

Dear Commissioner Caliboso,

On behalf of the Rocky Mountain Institute, we are pleased to present our comments on the Initial Concept Paper on Electric Utility Rate Design, as set forth in Act 95, Session Laws of Hawaii 2004.

We are providing comments on paragraphs 21, 29, 46, 53, and 58. Due to the nature of the questions posed, we have taken the liberty of combining our responses to certain issues in order to avoid repetition.

We would be pleased to present on the panels that will be held on November 22nd and 23rd, 2004 in Honolulu. Overall, we believe our testimony would add a fresh perspective in three areas:

- Paragraph 21: Overall economic viability of renewables in Hawaii, and the implications to an RPS scheme for Hawaii
- Paragraph 21 and 58: Critical factors in designing a successful RPS, and potential penalties for non-compliance as well as incentives for compliance in Hawaii
- Paragraph 46 and 53: Technical and economic factors regarding proposed Power Market Simulation and Status Quo Simulation.

We look forward to hearing from the Commission regarding the invitation to join the panels in these areas. I can be reached by email at kdatta@rmi.org.

Best regards,

Kyle Datta
Managing Director

TESTIMONY OF THE ROCKY MOUNTAIN INSTITUTE ON THE ELECTRIC UTILITY RATE DESIGN IN HAWAII: AN INITIAL CONCEPT PAPER

Paragraph 21:

Status and Prospects of regulation under RPS in Hawaii and elsewhere
Successful RPS schemes and electric utility rate design

1. Criteria for a Successful RPS

The creation of a successful RPS, like any policy making exercise, requires specialized knowledge about the resources to be regulated and clearly defined policy goals. There are many approaches to crafting a successful RPS, and in this comment, seven design principles that are ubiquitous and fundamental to RPS success will be explained.

The first two principles are that the RPS is socially beneficial as well as cost effective and flexible. Next, the RPS must be predictable, nondiscriminatory, and enforceable. Finally, it must be consistent with market structure and compatible with other policies.

Principle One: Socially Beneficial

"A well-designed RPS will support increased renewable energy production, and thereby contribute to an improvement in environmental quality, to increased diversity in energy supply, to decreased risk, and to other politically chosen objectives."[1]

The best practices for implementing a socially beneficial RPS are to ensure that: the RPS rules lead to new renewable generation; renewable energy purchase requirements increase over time (resulting in increasing benefits); the net amount renewable electricity serving the state is increased; the RPS applies to all retail sellers (or as many as possible); eligibility decisions are based on policy objectives and the evaluation of the need of the projects to receive extra market revenue; customer sited renewables projects that meet policy objectives and renewable energy applications that save electricity are considered for eligibility; eligibility of out of state projects are guided by social objectives of the RPS; and if policymakers want renewable resource diversity, the consideration of resource tiers, credit multipliers or complementary policy approaches.[2]

Principle 2: Cost Effective and Flexible

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[1] R. Wiser, K. Porter, R. Grace, C. Kappel, *Evaluating State Renewable Portfolio Standards: A Focus on Geothermal Energy*, 03 September 2003, Available at: https://www.geocollaborative.org/publications/RPS_Summary.pdf

[2] *Id.* at 45

"A well designed RPS will be implemented and administered in a straightforward, flexible, cost-effective, and not unduly burdensome manner."[3]

The best practices for implementing a cost effective RPS are to ensure that: renewable energy purchase requirements are achievable based on the available resources; sufficient lead-time exists between the time when the target is set and when the policy takes effect to allow for project development and construction; minimal regulatory intervention is need; a tradable renewable credit system for trading and verifications is used, and that policy makers have considered establishing a cost cap (depending on potential supply scarcity).[4] To successfully implement a flexible RPS measures such as: compliance flexibility tools and limited flexibility for regulators to alter RPS percentage increases in extreme circumstances. Finally, eligibility rules must be clear and consideration should be given to establishing long term contracting standards to increase stability.

Principle 3: Predictable

"A well designed RPS will provide market stability for all participants, reducing regulatory risk for generators and LSEs and improving the ability of renewable developers to obtain financeable long term contracts."[5]

The best practices for implementing a RPS that is predictable is to ensure that: there is strong legislative and regulatory support for the RPS policy; the renewable energy targets enhance long term contracting; eligibility and RPS rules are clearly defined; enforcement mechanisms are established; the RPS applies to all retail sellers; and long term contracting standards are established.[6]

Principle 4: Nondiscriminatory

"A well-designed RPS will be applied fairly, consistently, and proportionately to all market participants and customers."[7]

The best practices for implementing a RPS that is nondiscriminatory ensure that: the RPS applies to all retail sellers and all potential sellers; the RPS is applied on an energy basis, not a MW capacity target; prudently incurred RPS compliance costs are recovered in electricity rates; eligibility decisions are made fairly, based on social benefits and technologies; customer projects qualify for the RPS; and renewable energy resources are compared in a fair manner when designing contracting standards.[8]

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[3] *Id.*

[4] *Id.*

[5] Wiser et al., *supra* note 1, at 46.

[6] *Id.*

[7] Wiser et al., *supra* note 1, at 47.

[8] *Id.*

Principle 5: Enforceable

"An effective RPS will be enforceable, ensuring that the policy's renewable energy targets and broader goals are achieved."[9]

The best practices for implementing an RPS that is enforceable is to ensure that: clear rules for enforcement of noncompliance are established; consideration of alternative compliance mechanisms is taken; and strong oversight by regulators.[10]

Principle 6: Consistency with Market Structure

"A well designed RPS will be consistent with and complement the structure of a state's electricity market, whether regulated or restructured."[11]

The best practices for implementing an RPS that is consistent with the market structure is to ensure that: the RPS applies to all potential suppliers; the RPS relies on renewable credits to demonstrate compliance; the RPS builds in compliance flexibility; long term contracting standards are established; and prudently incurred RPS compliance costs will be recovered in electricity rates.[12]

Principle 7: Compatibility with Other Policies

"A well designed RPS will be compatible with other applicable policies and regulations in the state, and where possible, the broader region."[13]

The best practices for implementing a RPS that is compatible with other policies is to ensure that: compliance flexibility mechanisms are designed to minimize conflict with fuel source or emissions disclosure requirements; other renewable energy policies are not designed to distort RPS compliance; in markets for emission rights, renewable electricity or TRCs , all emissions rights remain intact and not sold to other parties; and state RPS rules are developed that authorize the RPS administrator to accommodate the possible creation of a federal RPS in the future.[14]

2. What Has Been Adopted Elsewhere?

There are fourteen states with RPS programs in place (Arizona, California, Connecticut, Hawaii, Iowa, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, Rhode Island, Texas and Wisconsin), and three states that have RPS – like programs in place (Illinois, Pennsylvania, and Minnesota). No two state plans are identical due to

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[9] Wiser et al., *supra* note 1, at 48.

[10] *Id.*

[11] *Id.*

[12] *Id.*

[13] Wiser et al., *supra* note 1, at 49.

[14] *Id.*

the need to individualize the RPS to meet state goals and incorporate resources efficiently and effectively.

Types of Goals Specified

Iowa, Minnesota and Texas have RPS policies that require a fixed amount of generation from renewables.[15] The consequence of setting a fixed amount of generation is that the absolute amount of renewable energy production will not increase or decrease with growth or decline in end use sales.[16]

Arizona, California, Connecticut, Hawaii, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, Wisconsin and Rhode Island all have RPS programs with a percentage goal. The percentage of electricity that must be produced or sold from renewable resources varies from Arizona's 1.1% 2007 goal to California and Hawaii's 20% goal by 2017 and 2020, respectively. All states except for Maine have RPS goals that increase over time which allow goals to be met and success to be evaluated along the way.

Resource Eligibility

No two states have the same resource eligibility. States may choose to promote or discourage certain types of resources depending on the state's RPS goals. For example, if a state seeks to encourage development of new renewable resources, and has an existing hydropower plant that does not need financial support, that state may choose to exclude hydropower from the RPS eligibility. However, if a state's RPS goal is simply to increase the diversity of the available energy sources, it should include all renewable energy options available.

Connecticut, New Jersey and Maryland divide their renewable energy into two classes, each with separate compliance percentages. Class I includes, but is not limited to, renewable energy sources such as solar, wind, fuel cells, landfill gas, and sustainable biomass. Connecticut phases out Class II renewables for meeting the increased compliance standard starting in 2004, New Jersey phases Class II out in 2008 and Maryland in 2018.

New Mexico weights renewables differently to encourage a diverse mix: 1 kWh of wind or hydro power equals 1 kWh toward compliance; 1 kWh of biomass, geothermal, LFG, or fuel cell equals 2 kWh; and 1 kWh solar equals 3 kWh.[17] Nevada also weights certain renewables more heavily than other for compliance. 1 kWh of distributed

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[15] Sam Schoofs, *A Federal Renewable Portfolio Standard: Policy Analysis and Proposal*, 06 August 2004. Available at: http://www.wise-intern.org/journal04/WISE2004-SamSchoofsFinalPaper.pdf

[16] Nancy Radar and Scott Hempling, *The Renewables Portfolio Standard: A Practical Guide*, February 2001. Available at: http://hemplinglaw.com/articles/RPS%20FINAL.PDF

[17] Wiser et al., *supra* note 1, at 55.

renewable generation equals 1.15 kWh, 1 kWh customer sited photovoltaic energy equals 2.4 kWh and specific customer-sited waste tire facilities receive .07 kWh.[18]

California simultaneously encourages development of new renewable resources and sustains current renewable energy by allowing geothermal that existed before 26 September 1996 to count toward a utility's baseline quantity of renewable energy, but prohibiting it from meeting the 1% incremental increase requirement.[19]

Who Must Comply with RPS?

The RPS usually applies to investor-owned electric utilities and competitive energy service providers, with most states exempting public owned utilities. Wisconsin is one of the only states that requires municipals and co-ops to meet the RPS along with the investor-owned utilities.[20] California also offers only a partial exemption to publicly owned utilities.[21]

Nine states exempt municipal utilities from compliance with the RPS (Arizona, Connecticut, Iowa, Maine, Massachusetts, Nevada, New Mexico, New Jersey and Texas). Six of these states also exempt cooperative power companies (Connecticut, Iowa, Maine, Massachusetts, Nevada, and New Mexico). The RPS creates benefits for the entire state, whether it is environmental, creation of fuel diversity, economic development or technology development. When some retail sellers are exempt from the RPS requirement, it increases the cost for the remaining retail sellers (and their customers) unfairly.[22] Only a portion of the utility sector is forced to pay for a benefit that all consumers enjoy.

However, these minor exemptions will probably not be detrimental to the success of the RPS. More major exemptions will destroy the impact of the RPS requirements, as shown in Connecticut where over 95% of the total load of the state was exempted, effectively undermining the RPS policy. [23]

Minnesota is the only state that requires only one utility, Xcel Energy, to meet a 10% RPS policy. All other utilities have the same goal of 10% which they are expected to make a good faith effort to comply with by 2015.

Creating Flexibility with Compliance Options and Credit Trading

The most popular and efficient way for retail sellers to meet the RPS standard is by using tradable renewable energy certificates (REC). RECs add flexibility, reduce the

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18 *Id.* at 54.

19 *Id.* at 52.

20 *Id.* at vi.

21 *Id.* at 32.

22 Rader et al., *supra* note 16, at 44.

23 Wiser et al., *supra* note 1, at 32.

cost of compliance, and track and verify compliance for the RPS. Four states have credit trading schemes within their own boundaries (Nevada, New Mexico, Texas and Wisconsin).

Texas was the first state to create and use a tradable renewable credit system, and it was administered by the Electric Reliability Council of Texas (ERCOT).[24] ERCOT awards TRCs to registered renewable facilities on a quarterly basis and also keeps track of retail sellers' TRCs. Electricity retailers are required to fulfill their portion of renewable energy requirements by presenting RECs to the ERCOT on an annual basis.[25] The tradable RECs are issued for each MWh of eligible renewable generation located within or delivered to the Texas grid.[26] After three years all TRCs are retired, although there is an early compliance allowance.[27] There is also a three month grace period following each compliance period to allow for retail sellers to fulfill their RPS.[28] Texas' system is considered to be one of the most successful TRCs in the country, not only because it has achieved new wind power additions but also because it has done so at reasonable rates.[29]

Regional trading credit systems are also becoming popular. Currently, there are two established, both in the East. Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont are served by NEPOOL Independent System Operator which tracks trading between these states.[30] Only Connecticut, Maine and Massachusetts have a RPS, but the system allows other non -RPS states to generate renewable energy and trade the credits using NEPOOL. Also, PJM has established a regional trading organization "that serves all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia".[31]

Alternatively, some states such as Iowa and Pennsylvania do not offer REC trading. Iowa relies on contract-path enforcement, Pennsylvania does not address trading schemes in the RPS.

3. Integration with Utility Rate Design and the IRP Process

The setting and design of rates is extremely important and is "one of the regulator's most effective means by which to achieve desired policy objectives," because no matter

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24 Wiser et al., *supra* note 1, at 60.

25 R. Wiser and O. Langniss. *The Renewables Portfolio Standard in Texas:An Early Assessment*, November 2001. Available at: http:// www-library.lbl.gov/docs/LBNL/491/07/PDF/LBNL-49107.pdf

26 *Id.* at 4.

27 *Id.* at 60.

28 *Id.* at 3.

29 *Id.* at 4.

30 *ISO New England, Overview of ISO New England, March 2004. Available at* http://www.iso-ne.com/iso_news/Information_Kit/01_Overview_of_ISO_New_England.pdf

31 PJM Interconnection, *Overview*, July 2004. Available at http://www.pjm.com/about/overview.html

how rates are set, they will offer incentives.[32] The key is to use rate design to encourage efficient electricity use and to adhere to the NARUC principle that the most profitable course of action for the utility is the least cost path for society. With this in mind, the integration of RPS with utility rate design is equally important.

Renewable power acts as a hedge on fossil fuel costs and can cost effectively lower total rates to consumers. As discussed below, the addition of renewables to the generation portfolio reduces the overall risk of that portfolio vs. the volatility of the fossil fuel markets. Regulators have struggled with incorporating the concept of risk reduction vs. future market prices, as demonstrated in the regulatory and market debacle of the California Energy Crisis of 2000-2001.

Utilities under traditional rate regulation, such as those in Hawaii, pass through their fuel costs to consumers, and thus have no incentive to take actions that would reduce these fuel costs. Further, since utilities earn a rate of return on the capital used for investments in their own generation facilities (typically fossil fuel plants), they have a disincentive to allow independently produced renewables to enter the market place, even if they are the least cost solution.

Although the Integrated Resource Planning process is the mechanism for determining the most prudent mix of resources, this has not been used as an enforceable guide to utility actions within the State of Hawaii. Worse, the IRP process in Hawaii has been (and continues to be), poorly executed, so that the assumptions regarding future fossil fuel prices, as well as the relative costs of renewable vs. fossil fuel plant costs, are not reflective of either current or projected market conditions; interconnection costs for renewables are often overstated relative to fossil, and the process has been systematically skewed in favor of fossil fuels resource alternatives. The Hawaii IRP process has never incorporated a quantitative assessment of risk reduction in the overall generation portfolio. Therefore, while the IRP process could serve as a good guide of what mix of renewables are cost effective in Hawaii, it does not. We are hopeful that the Commission's oversight in the current round of IRP will address the past shortcomings.

This failure is especially important because under that Statute, Hawaii's utilities must only comply with the RPS to the extent that renewable resources are determined to be cost effective.

We support the proposal that prudently incurred RPS compliance costs should be recoverable to maintain a successful RPS policy.[33] Wiser et al have written that in order to maintain an RPS that is nondiscriminatory[34] and consistent with market structure[35]

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32 F. Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, December 2000. Available at: http://www.raponline.org

33 Wiser et al., *supra* note 1, at 47-48.

34 "A nondiscriminatory RPS will be applied fairly, consistently, and proportionally to all market participants and customers." *Id.* at 47.

prudently incurred RPS compliance cost should be recovered from end-use electricity customers. It is important that there is clear and unambiguous guidance from electric utility regulators on what the definition of "prudently incurred costs" is as well as if other transmission related costs can also be recovered through rates. RMI believes that if the IRP process were correctly executed in Hawaii, in accordance with the principles of Energy Resource Investment Strategy (ERIS), which explicitly takes risk adjustments into account, then the PUC would have guidance on what level of renewable resources would be prudently incorporated into rates.

We will address the broader question how to incorporate the renewable costs into Performance Based mechanisms in the response to Question 53.

4. Funding Mechanisms

In general, renewable portfolio standards are funded by the utility through its procurement of renewable power and then ultimately by the ratepayers in rates.

Arizona is unique in its RPS design because the Arizona Corporation Commission authorizes the IOUs and cooperative electric service providers to use a customer Environmental Portfolio Surcharge for compliance.[36] For residential customers, this is the lesser of a .000875 dollars/kWh or 35 cents/month surcharge that the retail electricity sellers charge to pay for their RPS compliance. Small commercial customers pay a flat rate of $13/month, and customers with a demand of over three MW a month for three consecutive months pay $39/month.[37] Interestingly, Arizona has not yet achieved 100% compliance because retail sellers will meet the RPS policy until the funding runs out.[38] The major reason for non-compliance is Arizona's lack of a penalty.[39]

Please see Appendix 1 for specific information on each existing state RPS and their penalty and funding mechanisms.

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35 "A RPS that is consistent with market structure will be consistent with and complement the structure of a state's electricity market, whether regulated or restructured." *Id* at 48.

36 *Final Rulemaking for the Environmental Portfolio Standard*, 8 February 2001. Available at: http://www.cc.state.az.us/utility/electric/environmental.htm

37 *Id.*

38 Wiser et al., *supra* note 1, at 34.

39 *Id*

Paragraph 21:

Various Alternatives for Renewable Energy Resources in Hawaii
Viability of renewable energy investments
Locational Cost of Renewable Energy in Hawaii

1. Various Alternatives for Renewable Energy Resources in Hawaii

Hawaii is blessed with a climate that is especially conducive to a broad range of renewable resources. These resources, and the commercial projects that have been proposed have been well characterized by both the Hawaii DBEDT www.state.hi.us/dbedt/ert/renewable.html and by Bollemier and Associates, and Karen Conover of Global Energy Concepts. The availability of renewable resources in Hawaii has been most recently characterized by Bollemier and Associates, *"Study of Renewable and Unconventional Energy in Hawaii"* see http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf.

All of these studies characterize the broad mix of renewable technologies including wind, geothermal, solar PV, solar thermal electric, geothermal, biomass and wave energy. Virtually every major study done on renewables in Hawaii suggests that the technical potential is at over 3.5 million MWh or 25—28% of total projected demand by 2018.

2. Viability of Renewable Energy Investments

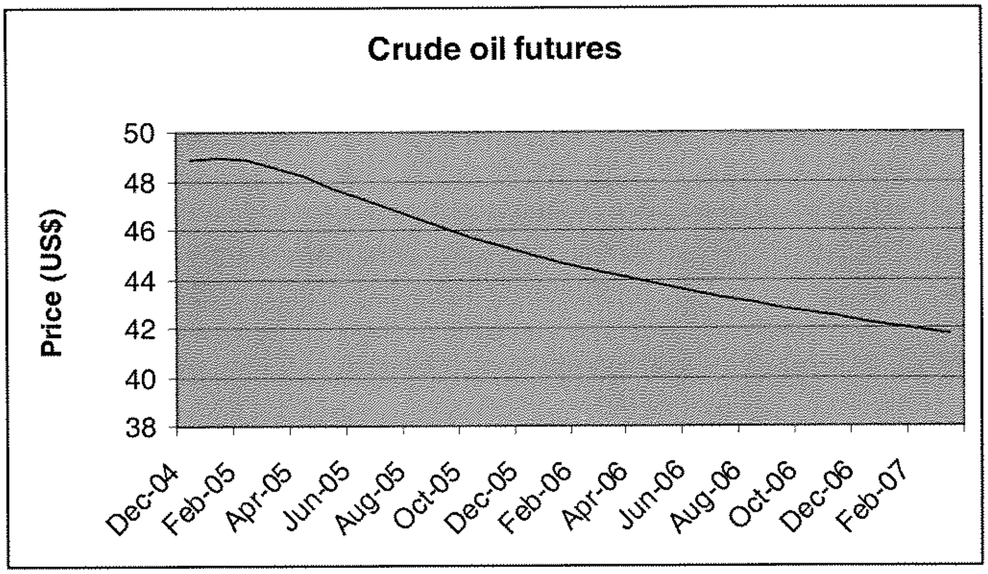
The economic viability of renewable energy in Hawaii depends on several factors which we discuss in detail below:

a. Oil prices and price volatility
b. The cost of renewable power technologies
c. The degree of capacity credit assigned to renewable technologies
d. System integration and interconnection costs
e. Financial engineering and tax credits
f. Hedging Value

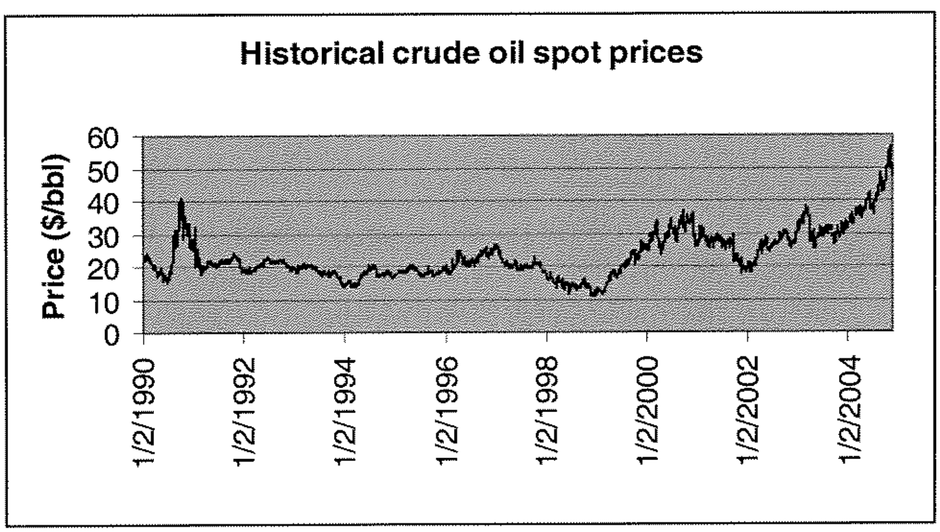
a. Oil Prices and Price Volatility

Renewables serve as a hedge on fossil fuel costs, and displace fossil fuel generation by the utility. Thus, the economic viability of renewable power is inextricably linked to the future price of fossil fuels, particularly oil. Although oil prices are notoriously hard to forecast, the near term price is evident in the futures market.

The following chart gives the NYMEX futures price of crude oil, which, while trending down from $50/bbl, remains far higher than historical levels.[40]



Price fluctuations in oil are not reflected in the futures market, but can be seen clearly in the following chart of crude oil spot prices.[41] Thus, the volatility of oil is extremely high, and becoming higher.



Finally, taking a 100 year view, we can see that oil prices in real dollar terms have reached a level of price and volatility not seen for nearly 80 years. It is very clear that the age of cheap oil is over.

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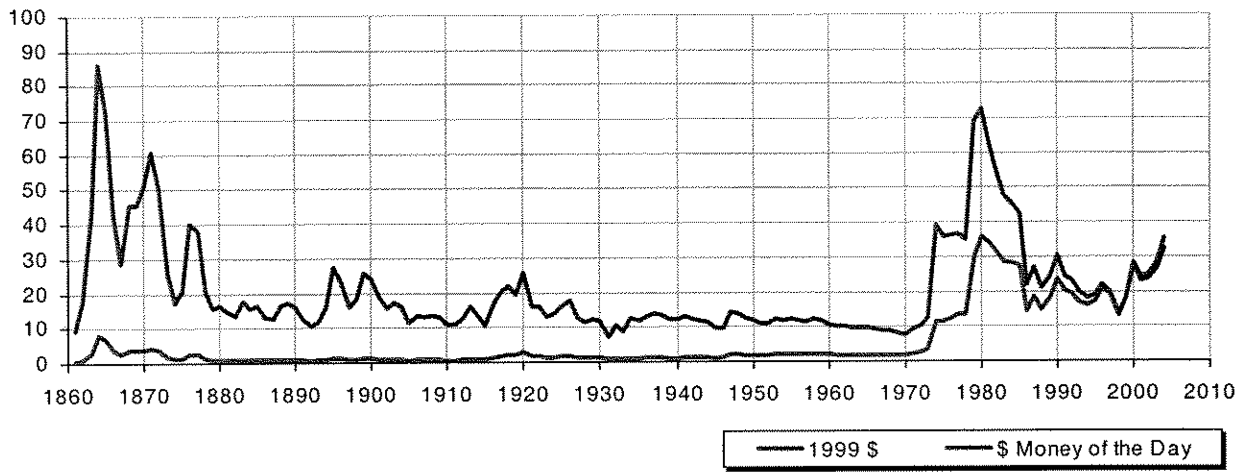
[40] NYMEX.com. Light, sweet, crude oil, 11/11/04 session. Accessed on 11/11/04 at http://www.nymex.com/jsp/markets/lsco_pre_agree.jsp.

[41] EIA (Energy Information Administration). US Crude Oil spot prices. Available at http://www.eia.doe.gov/oil_gas/petroleum/info_glance/crudeoil.html.

Crude Oil Prices, 1861-2004
US Dollars Per Barrel[42]



The Rocky Mountain Institute has recently issued a major new study on oil and its alternatives, *Winning the Oil End Game* (2004) (see www.oilendgame.com). Our conclusion on oil price movements is that three major factors will determine future prices:

- The balance of global supply and demand
- The risk premium associated with terrorism and market disruption
- The degree of technical trading in the commodity

Today, these three factors have conspired to send oil prices soaring into the high $40s-low $50s/bbl. The fundamentals of supply and demand have been shift by China and India's voracious appetite for oil combined with continued US growth so that supply and demand are balanced at 82 MMbbl/d. Hence any disruption in supply can send prices higher. Whether this continues depends on the ability of the US, China and India to move down a more energy efficient path for transportation and economic development, more than it depends on the ability to bring on new supplies.

Thus, we conclude that we must recognize that oil is likely to maintain a higher price plateau of mid $40s in the near term, with a longer-term equilibrium in the mid $30s. Unfortunately, HECO and HELCO, in the current IRP analysis, have remained wedded to the 2002 oil price forecast, which is expects crude oil prices (in real dollar terms) to remain in the mid $20s to low $30s. Thus, they grossly underestimate the economic viability of renewables and their value on the system.

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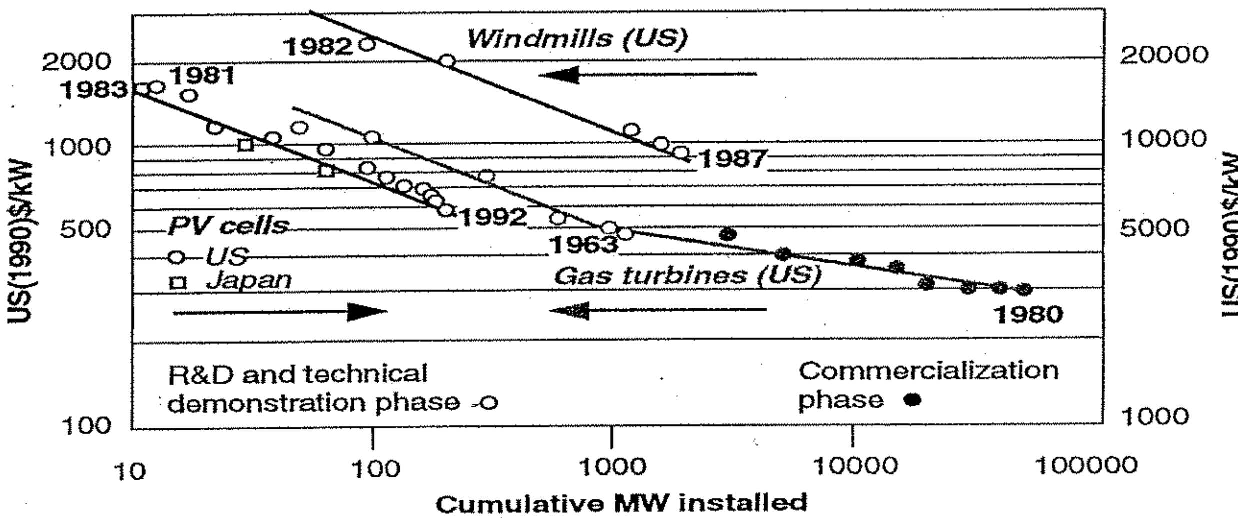
[42] Shell 2050 Scenarios. Available at *http://www.eia.doe.gov/emeu/international/petroleu.html#IntlPrices*

b. The Cost of Renewable Power Technologies

Overall the cost per kW, and cost per kWh of renewable technologies has been steadily declining due to learning curves, cumulative manufacturing experience, and increasing scale of renewable power (particular wind turbines and solar PV). The chart below from the IIASA demonstrates the cost reductions that have already occurred for renewable technologies.

Progress Ratios for Photovoltaics, Windmills, and Gas Turbines



Source: IIASA/WEC (1995)

Renewable power technologies, such as wind, are already at the 5¢/kwh (levelized) threshold, and most industry sources expect this to drop to 4¢/kwh by within a decade.

The cost of renewable power technologies in Hawaii has recently been fully characterized by Global Energy Concepts. This study available from DBEDT evaluates the cost of renewable technologies in Hawaii, taking into account the higher factor costs for transportation and labor.

HECO and HELCO have used Black & Veatch engineers in the IRP process to evaluate the costs of generation technologies in both the last round of IRP and the current round. In the most recent 2004 IRP round the Rocky Mountain Institute and others have challenged the Black & Vetch estimation of renewable power costs. In RMI's recent letter to the HELCO IRP process, we raised the following concerns:

- The costs for renewable resources, particularly wind plants, appear to be highly inflated relative to their fossil counterparts. For example, the real dollar costs of wind plants increased 52% vs. 1998 compared to only 23% for fossil plants.

- Interconnection costs appear to be extraordinarily high for all renewable resources except those owned by HELCO. T&D interconnection at HELCO's Lalamilo wind site is merely $90/rated kW, while it is $270—$700/per rated kW for competitors' wind sites.

- The scale chosen for renewable resources has been set arbitrarily low. The wind farms are capped at 20 MW, even though the resources at the sites could be far larger. Solar systems at utility scale (1 MW) have been excluded with no basis. Further, B&V shows virtually no economies of scale for larger scale wind farms, contradicting nearly all known literature on the subject.

The Rocky Mountain Institute, B&V, HECO and HELCO have all agreed to review the B&V cost estimates in order to address these irregularities. Our current advice to the Commission is that these estimates not be relied upon until these issues are resolved, but rather the independent assessment done by GEC be the guide for expected renewable technology costs in Hawaii. We will appraise the Commission on our findings from this review and provide it as supplemental comment to this proceeding.

c. The Degree of Capacity Credit Assigned To Renewable Technologies

The economic viability of all generation plants depends on the revenue streams they receive. Fossil plants, which are firm and dispatchable, receive both capacity and energy payments. Most renewables power generators receive only energy payments for some or all of the energy they produce, and essentially given zero capacity value. Such is the case in Hawaii. Given the very high avoided capacity costs in Hawaii (>$1000/kW), a higher capacity value can greatly increase the economic viability of renewable power projects.

Although wind has typically been procured by utilities on an energy only basis, there is increasing acceptance that wind generation does contribute to system reliability, and therefore has capacity value. Standard utility reliability or production cost models can be used to calculate wind capacity value, or simpler models that approximate this value can be employed. The evidence is increasingly clear that many renewables should be given some degree of capacity payments, and more US utilities are incorporating this reality into their generation planning processes and avoided cost payments. We explain the reasons why below.

While fossil fuel plants tend to have high capacity values per rated MW (on the order of 95%), wind farms are often assigned low capacity values (often zero) due to the high variability of their output. If a wind farm cannot guarantee a particular capacity, other resources must be committed as back up in an amount equal to the wind farm's output. But is this conventional wisdom approach accurate?

Geographically distributing wind resources has the potential to reduce the variability of the portfolio output to such an extent that the portfolio is worthy of capacity credit. Topography and weather patterns contribute to different wind regimes in different locations. In essence, the variability of wind in one geographical location to some extent cancels out the variability of the wind in another location. Further, portfolios of renewable resources may demonstrate covariance in output during peak periods, so that the portfolio of renewables deserves higher capacity credit than each individual resource consider in isolation.

Furthermore, winds sometimes exhibit seasonality or diurnal variation that results in a statistically significant peak coincidence. In this case, the wind farm contributes positively to the overall reliability of the system and deserves an associated capacity credit.

Methods of calculating capacity credit have been developed by wind and utility experts around the country. One approach to determining a wind farm's capacity credit is to calculate its effective load carrying capability (ELCC), a metric created by the National Renewable Energy Laboratory (NREL), and applied most recently by the California Energy Commission (CEC) in their renewable generation integration cost analysis. This approach is useful because it can be applied to any type of generating resource, whether fossil fuel or renewable. The ELCC equation says that the increase in capacity that results from adding a new generator can support x more MW of load at the same reliability level as the original load could be supplied.[43] The ELCC is based on the loss of load probability (LOLP), which is the probability that enough generation units are on forced outage that the utility is unable to meet its load, thereby quantifying the risk of not supplying enough generation to the system. When this method was applied to existing wind farms in California, capacity credits were determined to be 22-26%. Since these existing California wind farms were built, turbine technology has been developed to improve energy capture at low wind speeds. The CEC believes if this technology installed at the existing sites, the capacity credits would be significantly increased. California is not alone in using this methodology. In the review of Xcel's 1999 integrated resource plan, all parties including Xcel and the Colorado Public Utility Commission agreed to adopt ELCC as the wind capacity value measure of choice.

While this is a rigorous method, the CEC and others have recognized that this iterative approach is perhaps overly complicated and time consuming, and have made efforts to develop simpler methods. One of these methods calculates the capacity factor of the wind farm over the top 10-20% of load hours and using this as an approximation for the ELCC. This approach is substantially more generous to wind than the iterative ELCC method.

A third method, and perhaps the most conservative, involves calculating the mean and standard deviation of an optimized portfolio of wind resources. Capacity credit is then

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[43] Kirby, Brendan, et al. *California Renewables Portfolio Standard: Renewable Generation Integration Cost Analysis, Phase 1.* California Energy Commission. December 2003.

assigned at the 95% probability level (i.e.-there is a 95% probability that power will be produced at that level or above).

In Hawaii, wind data from geographically dispersed locations exists that make possible an analysis of the reduced variability from a portfolio of wind. A similar analysis conducted with wind data from North Carolina found that distributing wind between three sites around the state could result in a portfolio variability equal to roughly 30% of the average variability at any individual site. This same data can also be easily compared to determine whether wind around the state exhibits any statistically significant peak coincidence. Geographical dispersion and peak coincidence can increase the viability of renewable energy investments.

We conclude that evaluations of renewable technologies in Hawaii either within proceeding, as part of an IRP, or for the determination of avoided costs, should estimate the reliability benefit of the renewable technology to the utility system, and provide capacity credits accordingly.

d. System Integration and Interconnection Costs

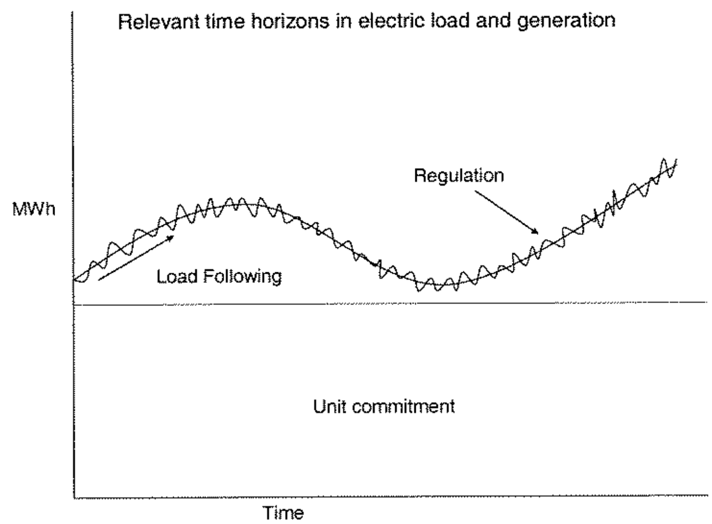
While wind is an intermittent generation resource, generation output from wind farms is more stable than the term "intermittent" may suggest. Grid connected wind farms typically have capacity factor levels of ranging from 25-40% or more over the course of a year. A common misconception about wind power is that turbines are either on or off and sit dormant for much of the year. In actuality, wind turbines are capable of partial output and most wind farms are generating at some level of generation during 70-90% of hours in the year. Further, there are a number of factors that smooth the output of a wind farm relative to variations in actual wind speed.

Much like electric load, wind exhibits a high variability that must be addressed by the utility on three time horizons:

- *Unit commitment*: most vertically integrated utilities decide which resources to dispatch 12-24 hours ahead of when they will be needed. These decisions to commit units are based on historical demand during the upcoming time period, recent trends in demand and weather, and the cost of each resource at that time. Unit commitments can be made because the dispatcher has confidence that a particular resource will or will not be available to produce a certain amount of power during the upcoming day. Because wind is currently so variable, utilities find it difficult to include wind in these day-ahead unit commitments. The amount of capacity committed for the upcoming day is generally the base amount that is forecast to be demanded during the entire period.

- *Load following*: Throughout the day, demand generally trends up or down. In response, utilities add resources to the generating mix, or increase or decrease existing resource energy output every five to ten minutes. Load following is somewhat predictable based on recent trends, and patterns of customers tend to be correlated. Because this pattern is fairly reliable across days, utilities must have resources ready that can be economically turned up or down throughout the day. To meet trending demand, the dispatcher must have control over the power output of these resources.

- *Regulation*: Regulation deals with minute-to-minute variations in the balance between generation and load; that is, the fluctuations (± 1 MW) around an underlying trend. These fluctuations are generally not easily forecast.



Integrating wind power on these three time horizons represents an added cost to the system. Several utilities, government agencies, and consultants around the country have undertaken studies of wind integration costs on their utility systems, and the results shown in the following table can help inform Hawaiian utilities.

Summary of Integration Costs from Previous Studies[44]

Study	Relative Wind Penetration (%)	Regulation ($/MWh)	Load Following ($/MWh)	Unit Commitment ($/MWh)	Total ($/MWh)
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00-1.80	1.47-2.27
Hirst	0.06-0.12	0.05-0.30	0.70-2.80	na	na
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3				3.19
Great River II	16.6				4.53
CA RPS Phase I	4	0.17	na	na	na

These studies report integration costs ranging from $1.47 - $5.50/MWh. Despite the differences in these utility systems in terms of generation mix and load profile, the results of their integration cost studies are remarkably similar; the overwhelming result being that integration costs, at a range of wind penetration levels, are low. There is no apparent reason to think that wind integration in Hawaii would fall outside of this range, except for minimum turndown issues on some systems.

The minimum turndown issue is based on the cost of turning down fossil fuel steam plants during the off peak hours, due to additional wind generation on the system when load is already low. These costs are essentially a heat rate penalty that the system would incur if the fossil steam plants were turned down below their minimum operating level and had to be reheated. While this is a valid cost to consider, it assumes that there are no energy storage options on the system.

Energy storage, such as pumped hydro, could be used to absorb the excess wind generation, eliminating the minimum turndown problem. This reinforces the point made earlier that renewable power must be considered in as a portfolio of resources and how the impact each utility system, in order to correctly assess the underlying economic value.

e. Financial Engineering and Tax Credits

Renewable projects are inherently more capital intensive than their fossil counterparts, since the fundamental economic tradeoff is capital costs vs. fossil fuel operating costs. The impact of financial engineering to either increase the leverage or lower the interest rate can be profound, as shown in the table below:

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44 Smith, JC et al. *Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date*. National Renewable Energy Laboratory. March 2004. NREL/CP-500-35946.

Securing PPA

Action	Types of Funds Used	Mechanism	Impact per $MM of Total Fund Contribution (¢/kWh)[45]
PPA Price Guarantee	Grant	Fund guarantees delta between project cost and market price to credit-worthy CT customers or retailers who sign 15-year PPA	0.042¢
Retailer Credit Guarantee	Reserve	Fund posts reserve equal to full price of one year of purchased power for green retailers to enable them to sign 15-year PPA	25,000 customers[46]

Lowering Renewable Financing Cost

Action	Types of Funds Used	Mechanism	Impact per $MM of Total Fund Contribution (¢/kWh)[47]
Guarantee Post-PPA Debt Service	Reserve	Fund guarantees debt service after PPA expires by reserving present value of debt payments in post-PPA years	0.055¢
Upfront Grant to Developer	Grant	Upfront lump sum subsidy of project costs	0.047¢
Production Incentives	Grant	Annual subsidy of project costs	0.042¢
Fund Debt Reserve	Reserve	Fund reserves amount equal to project debt reserve requirement (typically 6 months of debt payments) for duration of debt	0.010¢
Low Cost Equity	Investment	Fund supplies equity at reduced rate of return	0.009¢
Fund DSCR to 1.2	Reserve	Fund reserves present value of delta in project cash flows needed to ensure 1.4 DSCR over duration of debt	0.006¢
Low Cost Debt	Investment	Fund provides low interest (6.5%) loan to developer	0.005¢

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45 Impact of action on delivered cost of 100 MW wind project with base case cost of 5.1¢/kWh. Efficacy measure does not take into account Fund's expected return on investment

46 Number of retail customers covered per $MM of Fund expenditure, irrespective of project

47 Impact of action on delivered cost of 100 MW wind project with base case cost of 5.1¢/kWh. Efficacy measure does not take into account Fund's expected return on investment

Cascading Benefits to Retail Customers

Action	Types of Funds Used	Mechanism	Impact per $MM of Total Fund Contribution
Retail PPA Price Guarantee	Grant	Fund guarantees 10% customer discount vs. generation credit for retailers who sign 15-year PPAs	1,800 customers[48]

Comparatively little work has been done in Hawaii to determine the degree to which public-private financial partnerships could reduce the cost of renewables, without incurring direct costs to the state treasury.

Tax credits have a significant impact on the overall financial viability of renewable projects. The State of Hawaii has provided generous tax credits to renewable generation technologies such as wind and solar. The Federal Production Tax Credit of 1.7¢/kwh, which has been part of the recent energy bills but has expired in 2003, has a major impact on the economic viability of wind projects. Restoration of this tax credit would make most wind projects in Hawaii more cost effective than combustion turbines or combined cycle units running on No 2 fuel oil.

Finally, carbon credits should be included in the evaluation of renewables, using the global market prices for these credits. Now that the Russia has signed the Kyoto Protocol, this accord will take effect. The liquidity of international carbon credit markets is increasing, making the posted prices more reflective of the market. Although the US has not signed the protocol, and carbon credits can only be monetized in the voluntary markets such as the Chicago Climate Exchange, a long run analysis should take the carbon credit value into account.

6. Hedge Value against Fossil Fuel Prices

The viability of renewable energy investments increases when taking into consideration the value of renewables as a hedge against fossil fuel prices. Energy planning should focus less on finding the single lowest cost alternative and more on developing efficient generating portfolios—those that maximize expected return for a given level of risk, and minimize risk for a given level of expected return.[49]

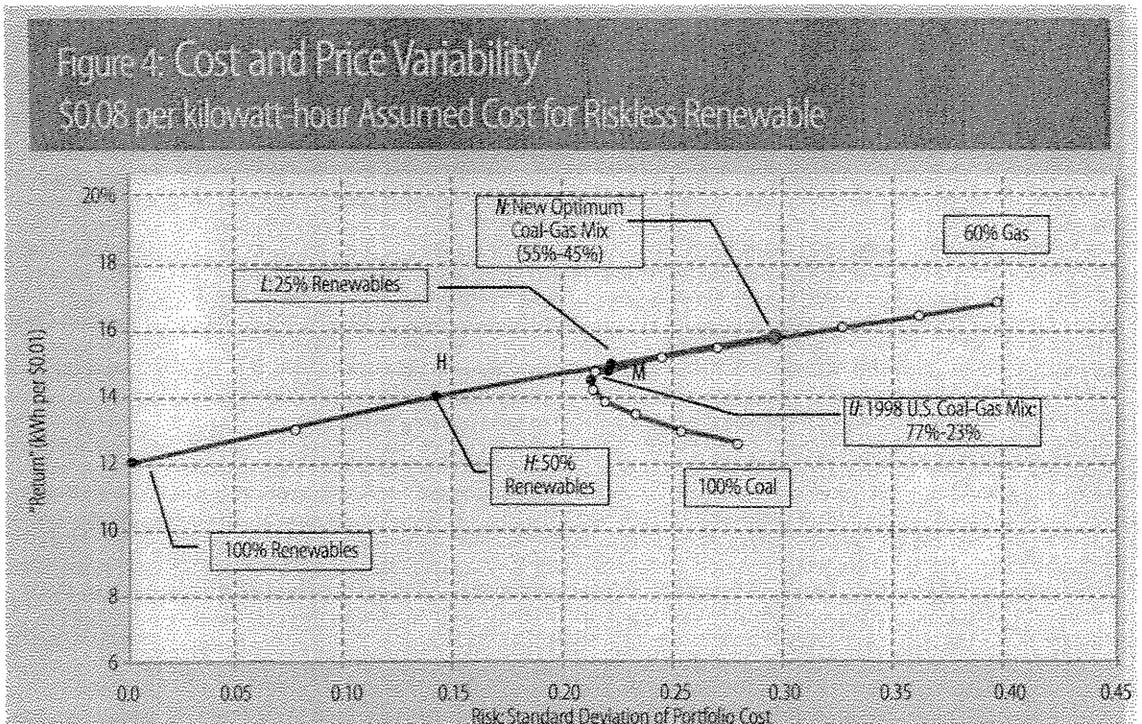
Price fluctuations make fossil fuels inherently risky; therefore adding "riskless" fixed-cost renewables to a portfolio of conventional generating assets serves to reduce overall portfolio cost and risk, even though their stand-alone generating costs may be higher.[50] By using established financial portfolio theory (see Appendix 2), Awerbuch

[48] Number of retail customers covered per $MM of Fund expenditure, irrespective of project

[49] Awerbuch, Shimon. *Applying Portfolio Theory to EU Electricity Planning and Policy-Making*. IEA/EET Working Paper, February 2003. EET/2003/03.

[50] *Id.*

demonstrates that the relative value of generating assets should be determined not by evaluating alternative resources, but by evaluating alternative resource portfolios.



Cheaper Renewables? If costs fall for renewable energy, returns will rise, flattening the straight line that runs at a tangent to the coal/gas risk-return curve. That would favor a higher share for renewables in the resource mix—plus a higher share for gas—at the expense of coal.

In the above chart from Awerbuch, point M represents the 1998 optimal mix of coal and gas fired generation in the US, based on a riskless renewable price of $0.12/kWh. If the price of renewables decreases to $0.08/kWh, the optimal mix of coal and gas (based on portfolio optimization of two risky assets) moves to point N. As renewables are added to the portfolio, the optimal portfolio shifts down towards point L. A renewable portfolio share of as much as 25% leaves overall portfolio generating costs unchanged, but provides significant risk reductions.[51]

In conclusion, the viability of renewable energy investments must take into consideration several factors. While integration costs are real, studies from around the country demonstrate that these costs are low. Wind investments could be given some level of capacity credit, based on the benefits of reduction in variability due to geographical dispersion and peak coincidence. Finally, because renewable investments are riskless, considered as part of a generating portfolio, they can act as a hedge against fossil fuel price fluctuations, and potentially decrease both the cost and risk of the generating portfolio.

[51] *Id.*

Paragraph 29:

> ***Impact of regulation on the behavior of utilities***
> ***Status and prospects of regulation under PBR in Hawaii and elsewhere***
> ***Alternative regulatory regimes available***
> ***Regulation and power sector restructuring in Hawaii***
> ***Successful PBR regimes and electricity utility rate design***

Extensive work has been done by NARUC, the Regulatory Assistance Project, and others on the history of PBR and the impact on utility behavior. Rather than restate that body of work here, RMI makes some observations of the impact of PBR schemes as they relate to the adoption of renewables by utilities.

The imposition of price caps (rate freezes) focuses utility management on cost reduction. In fuel costs are not included in the price cap, utilities would have little or no incentive to adopt renewables. This scheme is generally inflexible and creates a disincentive for adopting renewables.

Revenue Caps, indexed for growth, decouple rates and revenue, and remove the disincentive for efficiency and distributed resources. While the utility is neutral to the choice of generation resources, the utility is not entirely neutral to who develops these resources. The revenue cap essentially eliminates the upside from load growth, and the utility would need additional ratebased resources to ensure continued earnings growth to pay dividends. Purchased power is passed through the fuel adjustment clause and would not provide this earnings growth. Positive shareholder incentives based on sharing the total system value created by renewables would create strong positive incentives for achieving the RPS in the most cost effective manner.

In designing the PBR for Hawaii's utilities, the Commission needs to take into account the measurable and verifiable metrics for judging utility performance which should include:

- Total system costs (e.g. total bills)
- Rates
- System reliability and power quality
- Customer service
- Achievement of RPS

Thus, the performance incentives for the RPS should not be considered in isolation from the other incentives provided to the utility.

Paragraph 40:

Simulation Models
Objective of Baseline Simulations
The Choice of Base Year

In RMI's view, the development of simulation models proposed by the Commission in its White Paper will provide the Commission with a critically important new capability to regulate the utilities within the State of Hawaii. These models will provide an independent assessment of the avoided cost on the system and the viability of alternative investments in energy efficiency or renewable power. We commend the Commission for taking this bold move.

RMI's comments regarding power market simulation are derived from our experience with large energy modeling efforts, and the work that RMI's Managing Director, Kyle Datta, has lead during his tenure as partner in the energy practice of Booz Allen & Hamilton.

The proposed suite of models essentially duplicates the utilities' planning models, and then integrates the results into a projected rate model which can be used to develop a pro forma financial model for the utility. A few practical words of advice as the Commission embarks down this path:

- The objective of these models is to provide insight into the impact of renewable resources on the total system costs of the utilities and consumer rates. Models are inherently powerful for gaining insights into the relative value of different system configurations and the underlying assumptions are the most critical to the overall outcome. They should not be used as predictors of the future.

- 2003 should be adequate as a base year because it encompasses two critical trends: the increase in air conditioning penetration (and resulting rise in peak), and the greater systemic volatility in oil prices. These structural changes were not apparent to the state's utilities in 2002, and as a result, their reliance on 2002 (or earlier) studies for fuel costs and end use penetration of appliances in the current IRP is akin to driving by looking in the rear view mirror. The Commission should avoid making the same mistake.

- The generation model will need to be informed by a transmission flow model, to ensure that the generation resources can serve the projected loads. This issue will be especially important in the far flung systems of the neighbor islands, where transmission constraints do preclude economic dispatch.

- These models will need to be accompanied by a transmission expansion plan that must be an explicit element of the investment model. If the model seeks to recognize the value of distributed resources, a distribution expansion plan for Oahu will also be required (neighbor island systems are so small that transmission will already include the smaller 34kV lines that are typically part of distribution in larger systems).

- The generation and investment model can be then be used to calculate area and time specific costs, as was recently done for the California PUC by E3. Once these costs are known, the correct value of central generation, distributed generation, and demand side resources can be understood.

- Each utilities' capital structure is a corporate business decision. The financial model should not attempt to change the capital structure of the utility, since this can lead to endless debates on what is the optimal capital structure that the Commission staff will be unable to resolve. Instead, the existing capital structure should be used (i.e. the % of debt, preferred stock, and equity). The current credit rating of the utilities debt and associated existing bond covenants will then serve as constraint against unfettered capital spending by the investment model.

- The timing of capital additions represents one of the most vexing real world complexities for Hawaii's utilities. The 10 year odyssey of HELCO's Keahole power plant and the inability of HECO to get approval for transmission line expansions underscores the community opposition to new central generation system resources. The investment model must take the timing of siting and the risks to the overall system of larger lumpier resources into account.

Finally, the model should explicitly address the failure of the utilities' existing models to explicit account for the financial risk inherent in the generation portfolio. The primary rate risk for Hawaii's generation portfolio is the volatility in the cost of fossil fuels. As discussed in appendix 2, renewable resources will reduce the standard deviation of the expected costs of a generation portfolio vs. fossil fuel prices. Thus, the output of this model should not just be the expected value of rates under different generation configurations, but the expected value and the variance associated with these values.

The Rocky Mountain Institute had detailed the quantitative methodology to address these risks in its book, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size (2002).* Thanks to generous support from the Hewlett and Luce Foundations, we are able to offer our advisory support to the Commission on how to incorporate these issues into the proposed Power Simulation Effort.

Paragraph 46:

> *Objective of Status Quo Simulation Models*
> *The Choice of Study Period*
> *Design of Inputs*
> *Candidate Projects for Renewable Investments*

1. Objective of Status Quo Simulation Models

RMI concurs with the overall objective of the Status Quo simulation models as proposed by the Commission, with one modification. Due to the inherent volatility of the underlying fossil fuel price, the forecast of future rate designs should not be solely the expected value of rates, but the expected value and variance of rates over time. This addition to the Commission's proposed methodology will allow the Commission to understand the value that renewable resources have in cost effectively reducing fossil fuel risk to Hawaii's ratepayers.

2. The Choice of Study Period

RMI suggest that the Commission consider no more than a 20 year study period. The study period should last long enough for the existing capital plant to be amortized, and the least cost plant take effect. This will allow the Commission to see the longer term reduction is risk adjusted rates that could be enabled by an appropriate mix of renewable resources. Longer study periods should be avoided, since the relative accuracy of load and technology forecasts becomes increasing poor due to technology shifts.

3. Design of Inputs

Several factors should be considered in the design of inputs.

- The renewable projects considered should include all commercially available renewable technologies that are currently available or can be projected with a reasonable degree of certainty during the study period. While the IRP can be a starting point, the current characterization of renewable resources is unduly constrained. Studies by EPRI and NREL can be better unbiased guides to the full range of applicable resources and their current and projected costs.

- The appropriate scale of renewable resources should be considered, along with the correct determination of their system impact. Central renewable resources, such as wind farms, pumped storage or large scale solar thermal electric or solar PV should be assessed at the same range of scale as their fossil counterparts for true comparability. Distributed renewable resources, such as residential PV, small scale hydro, solar thermal and residential scale CHP fuel cells, should be evaluated on an aggregated basis, recognizing that these resources will reduce peak load at the point of consumption, and should be valued accordingly (see www. smallisprofitable.org).

- Fossil fuel costs should be updated to most recent 2004 market projects, using NYMEX forward curves, and the adjusted based on the best available forecast of oil prices. The implicit volatility in the oil prices forward curves can be used to garner a market estimate of the volatility associated with this commodity.

- When available, all credible commercially bids for renewable power projects should be included in the near term evaluation of resources. Commercial bids have the benefit of reflecting actual market conditions and costs, as well as known sites that can be evaluated within the utilities system. Both GEC and Bollemier have published recent studies of proposed renewable projects that should serve as an unbiased guide as to what projects are currently available.

4. Candidate Projects for Renewable Investments

The candidate projects for renewable investments should be consider in at least two time frames: "commercially available within the next 5 years" and "likely to be commercially available within years 6-15."

Near term commercially available resources have already been well described in the GEC and Bollemier studies. Although quite comprehensive, these studies do not include a few important renewable resources that bear consideration:

- Solar Thermal Storage Electric Generation (a firm renewable resource, available from Duke Solar, and under development by Sierra Pacific, already commercially demonstrated with 350 MW in California since 1990).
- High temperature fuel cells (MCFC from Fuel Cell Energy), available in MW scale and able to run on gas.
- Small scale residential fuel cells (5kW PEM CHP) available from Plug Power in 2005
- Ocean power systems that are currently under demonstration in Oahu (wave power buoys).
- Ocean Thermal Energy Conversion Systems
- Seawater chilling systems (if renewable demand side systems qualify under RPS)
- Convention hydrogen storage systems available from Norsk Hydro.
- Biofuels: including biodiesel as a renewable fuel input.

- Alternative geothermal configurations and sites (beyond existing Puna Geothermal facility)
- Landfill gas recovery systems

In the mid term, RMI suggests that the Commission consider the following:

- A broader spectrum of fuel cell technologies will be commercial available at the utility scale. SOFC, MC, and PEM systems should all be commercialized within this time frame.

- Existing renewable energy systems will have improved based on the cumulative experience curves with the technology. Reasonable projections for the improvement of these technologies are available from the IEA and NREL.

- Biomass gasification systems based on the Pearson process (under development by the World Energy Group on Kaui). This includes both the cogeneration of power from the syngas, but also the lower cost production of cellulose based ethanol.

- Hydrogen storage systems, particularly from electrolysis and bidirectional PEM fuels (see Proton Energy)

- Advanced storage systems such as vanadium redox flow batteries, compressed air storage in pipes, (note: storage systems must be considered in order to absorb a higher percentage increase in intermittent resources). See recent work from Sandia National Laboratories.

- Tidal power is a promising technology. There are four to five concepts being developed currently; one to three models are being commercialized in the U.K. and elsewhere. It is considered cost-effective by some U.K. authorities (see Verdant power (www.verdantpower.com)

- Off shore wind. While already commercially available, siting challenges place this technology in the mid term time frame.

Paragraph 46:

Objective of Alternative Scenario Simulations
The Choice of Study Period
Design of Inputs
Candidate Incentive or PBR Regimes
The nature, scope, and duration of penalties for future non-compliance with the RPS

1. Objective of Alternative Scenario Simulations

RMI concurs with the overall objective of the Alternative Scenario simulation models as proposed by the Commission, with one modification. Due to the inherent volatility of the underlying fossil fuel price, the forecast of future rate designs should not be solely the expected value of rates, but the expected value and variance of rates over time. This addition to the Commission's proposed methodology will allow the Commission to understand the value that renewable resources have in cost effectively reducing fossil fuel risk to Hawaii's ratepayers.

2. The Choice of Study Period

RMI suggest that the Commission consider no more than a 20 year study period. The study period should last long enough for the existing capital plant to be amortized, and the least cost plant take effect. This will allow the Commission to see the longer term reduction is risk adjusted rates that could be enabled by an appropriate mix of renewable resources. Longer study periods should be avoided, since the relative accuracy of load and technology forecasts becomes increasing poor due to technology shifts.

3. Design of Inputs

RMI's recommendations on design of inputs is the same as our response to Paragraph 46.

4. Candidate Incentive or PBR Regimes

In RMI's view, utility management responds best to combination of incentives and penalties that collectively remove disincentives to renewable power production and create positive incentives for implementation of the least cost generation portfolio, adjusted for risk. In order to create a coherent set of regulations, the choice of incentive will need to be linked with the choice of PBR regime. Each type of PBR regime has tradeoffs that should be acknowledged, and were discussed in the response to Paragraph 29.

A brief description of the types of incentives follows:

a. Bonus Incentives

Bonus type incentives provide for additional return on equity for the entire utility as a reward for achieving specific, measurable performance targets. The quantitative and verifiable nature of the RPS makes it good candidate for bonus incentives.

Bonuses may also be assigned directly to the kwh produced that either meet or exceed to PBR target. No bonus would be provided for failure to meet the target.

b. Additional Return On Ratebase

Regulators initially used additional return on ratebase for renewable and energy efficiency investments made by the utility. While these are easy to administer under traditional cost of service regulation, they tend to reward the most expensive resources that meet the total resource test, rather than the least cost resources. This approach can also be modified to reward specific types of resources within the generation portfolio.

c. Share Of Total System Costs

A more sophisticated approach that aligns the utility incentives with societies is to provide a share of total system cost savings from incorporation of renewable resources into the portfolio. In essence, this means that the utility will receive a portion of the fuel that it saves. This scheme would reward the utility for saving fuel, which would encourage fuel efficiency, or the use of renewable resources that do not use copious amounts of fuel to create energy. Even if only 10% of the fuel savings would go into the utility's pocket, and 90% of the savings would go to the ratepayers, this would still create a powerful financial incentive.

The following matrix may serve as a helpful starting point for the discussion regarding the appropriate combination of PBR regimes and incentives (note penalties will be discussed in next section):

PBR Regime	Renewable Incentive
Traditional rate of return	1. Rate base adder for renewable power plant investments done by the utility or IPPs 2. Overall utility ROE increased or decreased based on achievement of target RPS level
Traditional Rate of Return, Green Pricing Option for Consumers	1. Rate base adder for renewable power plant investments done by the utility or IPPs or 2. Bonus (¢/kwh) assigned to utility for renewable kwh produced or purchased to meet consumer demand expressed in green pricing option
Revenue Decoupling Revenue Cap approach	1. Utility receives share of total system savings as measured by societal resource test as incentive for incorporating cost effective renewables in the system. Or 2. Same as above, but based on total resource test.
Price Cap CPI-X Approach	1. Utility receives share of total system savings as measured by total resource test as incentive for incorporating cost effective renewables that lower risk adjusted rates.

In general, RMI believes that the revenue decoupling approach will achieve the greatest long term alignment with utility behavior and societal benefit. However, since revenue decoupling removes both the downside and the upside from the utility financial returns, it should be combined with a share of total system savings from renewables (or efficiency) in order to ensure that the utility has a steadily growing earnings stream from which to pay dividends.

In addition, one of the critical failures in traditional rate of return regulation is that the rate payer bears all the fuel price risk. The utilities in Hawaii have no incentive to manage fuel costs, yet, given the high oil prices fuel costs now account for nearly 50 % of total rates. The total fuel bill for electric power to the ratepayers of Hawaii was $1.3 billion in 2000 and we estimate that it could be over $2.0 billion in 2004. This $700 million dollar increase in annual electric rates is just as important to manage as other utility rate increases.

Utilities have resisted bearing financial responsibility for increased fuel charges, arguing that their margins make it financially impossible to accept the fuel price risk, and the negative impact it would have on the debt ratings and shareholder value. RMI understands these financial concerns. However, positive shareholder incentives to share in the savings created from reduced fuel costs and risks to Hawaii's ratepayers would have the benefit of creating utility incentives to lower total consumer energy bills through renewable power and energy efficiency. We believe that this incentive is the single most important incentive to align utility management behavior to achieving the RPS.

We note that any renewable incentive created should not create financial incentives for the utility to build its own renewable resources compared with procuring those renewable resources from others. Rate base adders under traditional rate of return regulation can create this societally perverse incentive, unless construed to include renewable power purchases from IPPs.

The Commission may wish to consider Tradable Renewable Certificates (TRC) in addition to the existing mechanism that allows the utility to pool the achievement of the RPS under the HEI umbrella. TRCs have the advantage of greater flexibility in terms of credit banking, potential trading with other state utilities (such as KIUC), continuation of flexibility in case of divestment of subsidiaries by HEI, and the ability of the Commission to provide extra credit for particular technologies. TRCs banking comes in three forms: unlimited (Texas, Wisconsin), long term (Nevada), retroactive (Massachusetts). Additional credits for specific technologies are utilized by Maryland.

5. Nature, Scope, and Duration Of Penalties For Future Non-Compliance With The RPS

Nature of Penalties Used by Other States

There are five states (Arizona, Hawaii, Iowa, Illinois, Minnesota, and Pennsylvania) that have a RPS or a RPS – like standard that do not have any penalties for non compliance.[52] A lack of a penalty does not necessarily mean that the RPS will fail. For example, Minnesota does not have penalties because it only requires Xcel Energy to meet it's RPS, and the state has not encountered any problems with non compliance. The rest of the retail sellers in Minnesota must make a good faith effort to meet the RPS. On the other hand, Arizona requires all IOUs and cooperative electric service providers to comply with its RPS, but unlike Minnesota, has yet to receive 100 percent compliance.

Most states that have penalties use financial penalties that are higher than the cost of compliance so that it is in the utility's interest to comply with the standard instead of trying to evade it. Currently, California and New Mexico are still working on creating their penalty. Maine and New Jersey allow for license revocation; Connecticut charges 5.5 cents/kWh; Massachusetts charges 5 cents/kWh for alternative compliance; Wisconsin's fines range from $5,000-$500,000; and Texas fines the lesser of $50/MWh per deficient TRC or 200% of the average TRC cost for deficient credits.

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[52] *Geothermal Wiser at 56-60*

Potential Penalty Schemes for Hawaii

There are two potential penalty schemes for Hawaii, both which have advantages and disadvantages. The first penalty scheme is a flat five ¢/kWh fine that is similar to Connecticut's 5.5 ¢/kWh fine. This penalty is advantageous because it is easy to administer. The Hawaii PUC could create an automatic enforcement that takes effect at the end of the compliance period and lower administrative costs. Flexibility could be integrated into this penalty scheme by allowing tradable credit banking. However, the penalty itself is static and does not reflect the costs to society.

A more economically efficient penalty scheme would be to charge the utility the full total system cost for failure to bring in the marginal renewable resource. The total system losses would be calculated in the same manner as the total system benefits in the incentives presented above. The difference is that the Commission must use its model to define the marginal renewable resource in any given year that should have been deployed but was not. Charging the utility the entire cost in ¢/kWh for each deficient kWh creates a powerful incentive for meet the RPS targets, and holds ratepayers harmless for the utilities failure to do so. It also holds the utility harmless if the Commission deems that no cost effective renewable resource was available, and hence is adaptive to a change in fossil fuel prices or power technologies.

We encourage the Commission to adopt both a penalty and an incentive scheme as it creates Hawaii's RPS regulations.

Appendix 1. State RPS penalty and funding mechanisms.
Excerpted from *Wiser et al.*, supra *note 1, at 56-60.*

	Tracking System and Flexibility Mechanisms	Penalty Mechanisms	Exempt Providers	Supportive RPS Funding
Arizona	LSEs can bank or trade renewable energy credits via compliance filings with the ACC. No central renewable energy credit registry or credit trading system exists or is planned. Excess purchases of renewables can be counted towards future annual RPS requirements or sold to other LSEs Waivers can be requested Arizona has a detailed system of credit multipliers for early installation before 2003, in-state installation or content, distributed solar, net metering, and utility green pricing A multiplier works in the following way: if an LSE earns an additional 0.5 credit, then 1 kWh = 1.5 kWh. Multipliers were additive, to maximum of 2, through 2003. LSE can offset ½ of requirement in 2001, ¼ of requirement in 2002-03, and 1/5 of requirement thereafter if they invest in an Arizona solar manufacturing facility	No explicit penalties until at least 2004. Starting 2004, if new solar requirements are not met then the ACC *may* be able to fine an LSE 30¢/ kWh; whether this is allowed is to be determined after the 2003 cost/benefit evaluation. The proceeds would then likely go to a solar electric fund to finance solar facilities. But, today, no penalties exist for non-compliance	The RPS initially only strictly applies to IOUs. Electric Service Providers (ESPs) do not have to participate until 2004, but if they choose to participate before that date, then they may receive Environmental Portfolio Surcharge (EPS) funds. Cooperatives, which are subject to ACC regulation, are collecting the EPS and must submit an RPS plan to the ACC or request further exemptions. Some have requested exemptions, while others have achieved partial compliance Municipalities and the Salt River Project are outside of ACC jurisdiction, so they are exempt	ESPs, Coops and IOUs can receive funds from the EPS fund to help fund the RPS. IOUs are also eligible for RPS support by reallocating DSM funds derived from the Systems Benefits Charge
California	Excess renewables procurement in one year can carry over to subsequent years, or inadequate procurement in one year can carry over to no more than the following three years. The CPUC is designing the details The CEC is charged with the responsibility of designing and implementing an accounting system to verify compliance with the RPS. The CEC is expected to develop an electronic system for the long term; whether TRCs are allowed to trade separate from electricity is to be determined by the CPUC later IOUs are not required to make annual RPS purchases if they are not creditworthy LSE obligations are limited by availability of SBC funds to cover above-market costs of purchases	Legislation allows CPUC to punish non-compliance through their general authority. Details of non-compliance penalties, if any, have not yet been finally established by the CPUC	Munis and irrigation districts are to implement RPS policies, but can do so in a flexible manner under the oversight and direction of their own governing boards IOUs are not required to make yearly RPS purchases until they are creditworthy	California's renewable energy SBC fund is to be used in large part to cover the above-market cost of LSE purchases of renewable energy under the RPS. LSEs are not required to meet RPS targets absent the availability of SBC funds for this purpose

	Tracking System and Flexibility Mechanisms	Penalty Mechanisms	Exempt Providers	Supportive RPS Funding
Connecticut	Will use the NEPOOL Generation Information System (GIS), which allows full certificate trading in New England. Also allows full certificate trading in New England. Also allows participation in TRC programs within NY, PA, NJ, MD and DE if approved by CT PUC Suppliers can make up deficiencies within the first three months of the succeeding calendar year	Electric suppliers that fail to comply during a year must pay 5.5 cents/kWh; collected funds are to be used to support the development of Class I renewable technologies through deposit to the "Renewable Energy Investment Fund". Such penalties are not recoverable in rates for distribution utilities	Under original law, through 2003, providers of standard offer and default service were exempt; this is no longer the case beginning 2004 Municipals and cooperatives are exempt Any supplier that provides electricity solely from Class II sources is exempt	SBC for renewable energy exists in state. The Connecticut Clean Energy Fund would fund RPS-eligible projects, and is required to fund 100 MW of projects under long-term contract
Iowa	Contract-path, with no banking. Legislative requirement for installed capacity	No explicit penalty, except through traditional utility regulatory oversight and enforcement by the Iowa Utilities Board	The capacity requirement was only placed on IOUs	No
Maine	Presently, credit trading is not allowed. However, the PUC has opened a rulemaking for adopting the NEPOOL Generation Information System, which would allow full certificate trading in New England If an LSE does not meet the 30% requirement, but has met at least 20% of the requirement during a compliance period, then the deficiency can be made up during the next compliance period, then the deficiency can be made up during the next compliance period so that over the two periods there is an average of at least 30% eligible resources. This "cure" period can be further extended for LSEs that can demonstrate ownership interest in new facility that will come on line within 2 years If LSE service begins less than 6 months prior to December 31, compliance period extends to the next December 31	Non-compliance can result in license revocation, fines or whatever the Commission deems appropriate. If a retail electric provider is threatened with license revocation, the Commission may provide the retail electric provider the ability to make a payment into the "renewable resource research development fund". The payment would be based on the difference in cost between ISO-NE market prices for eligible and non-eligible energy for every deficient kWh Penalties can be waived if RPS could not be met due to market conditions	Municipalities, cooperative and any entity exempt from electric restructuring do not have to meet the portfolio requirement	No

	Tracking System and Flexibility Mechanisms	Penalty Mechanisms	Exempt Providers	Supportive RPS Funding
Massachusetts	Will use the NEPOOL Generation Information System (GIS), which allows full certificate trading in New England LSEs can apply certificates to subsequent years. Excess certificates applied to a subsequent year cannot exceed 30% of a providers RPS requirement for that year Early compliance mechanism existed for 2002	Alternative compliance mechanism allows LSEs to pay 5 ¢/kWh to cover RPS requirements if they chose not to purchase renewable energy certificates If an LSE does not comply with either the RPS or associated reporting requirements, the Commission will issue a public notice of deficiency, will require an LSE to submit a 3-year plan detailing how future requirements are to be met, and can refer the LSE to the Department of Telecommunications and Energy Licensure, which can take further action, including license revocation	Municipalities, cooperatives and any entity exempt from electric restructuring do not have to meet the portfolio requirement	SBC for renewable energy exists in state. The Massachusetts Renewable Energy Trust is considering how it will support the development of long-term renewable energy contracts under the RPS
Minnesota	Original Xcel mandate: deadline-based capacity obligation 10% Goal: PUC may establish a TRC program. Upon creation of an RPS in a neighboring state with comparable resource eligibility, PUC may facilitate TRC trade between states For all utilities except Xcel, the 10% is a goal, requiring "good faith efforts" Xcel's 10% requirement is subject to "least cost planning" requirements; if implementation of requirement will jeopardize reliability, or is uneconomic, then requirement may be waived	Original Xcel mandate, and the new 10% goal, were required by legislation, and overseen by utility regulators. No explicit penalties beyond standard tools available to regulators	Xcel energy required to meet original renewable energy purchases, and required to meet 10% renewable energy goal, if the requirement does not impose undue economic or reliability impacts All other utilities in state must demonstrate "good faith efforts" to meet 10% goal; whether these efforts result in full or partial compliance is not yet clear	Minnesota's renewable energy fund is largely seeking to fund projects that would not otherwise succeed under the Xcel requirements and RPS 2003 renewables goal allows MN utilities that are in compliance with goal to apply 5% of their energy efficiency funds to support in-state renewable energy projects, with more restrictive eligibility rules for biomass

	Tracking System and Flexibility Mechanisms	Penalty Mechanisms	Exempt Providers	Supportive RPS Funding
Nevada	The Nevada PUC approved the use of tradable renewable energy credits in November 2002 TRCs are valid for a period of four compliance years following the compliance year in which the TRC was issued Dist. Gen. Receives extra-credit multipliers LSEs obligated to meet "estimated" RPS requirements	Administrative fines can be levied by the NPUc of at leas the cost differential between the cost of system power, unless an LSE can claim an exemption because not enough renewable power is available despite best efforts. This fine cannot be claimed in a rate case or paid-off by retail customers	Neither cooperatives nor municipal utilities are required to participate	None
New Mexico	New Mexico plans to use renewable certificates to track transactions between utilities and renewable suppliers. Certificates may be traded, sold or transferred Unused certificates may be applied for no more than four years from the date of issuance	The PUC's order says that specific penalties will be developed	Rural cooperatives and munis are exempt from the RPS. Texas-New Mexico Power Company is exempt until its all-requirements contract expires or is renegotiated	None specified
New Jersey	Legislation allowed the BPU to develop a renewable energy trading program in consultation with the New Jersey Department of Environmental Protection. Such a system has not yet been developed. The state is working with PJM to develop an energy tracking system within the ISO that may or may not include credit trading Flexible penalties for non-compliance	An LSE that is not in compliance is required to make-up that shortfall in the following year. An LSE that remains out of compliance may be required to submit quarterly reports and may be subject to license revocation or fines, or be unable to take new customers. If a basic general services provider (BSG) is fined, they will be prohibited from recovering fines in rates	Public power agencies do not have to comply with RPS requirements. Electric power suppliers and BSG providers both must comply with RPS requirements	SBC for renewable energy exists in state. The administrator does fund RPS-eligible projects located in New Jersey

	Tracking System and Flexibility Mechanisms	Penalty Mechanisms	Exempt Providers	Supportive RPS Funding
Pennsylvania	Tracking system not addressed RPS percentage requirements may be decreased if renewable requirements increase default service costs more than 2 percent	None specified	All but limited number of competitive suppliers serving default service loads are exempt	SBCs for renewable energy exist in state. These funds may support renewable projects that are eligible under the RPS
Texas	First state to create and use tradable renewable credits, administered by the Electric Reliability Council of Texas (ERCOT). ERCOT awards TRCs to registered renewable facilities on a quarterly basis, keeps track of retailers' TRCs, retires TRCs that are over 3 years old, and allocates the statewide renewable energy responsibility to competitive retailers All TRCs have a compliance life of 3 years, after which ERCOT will retire the credits. Early compliance allowance and 3-month settlement period are also provided Before 2003, an LSE is allowed a 10% TRC shortfall in any given year. After 2003, no shortfalls are allowed. If an LSE has a pre-2003 deficit, then the shortfall must be made up in the next compliance period	Penalty for non-compliance is set at the lesser of $50/MWh per deficient TRC or 200 percent of the average market TRC value for the deficient credits. The retailers must prove the average market value to the Public Utilities (PUCT) The PUCT may not impose a penalty on an LSE if the PUCT determines that "events beyond the reasonable control" of the retail electric provider prevented complying with the RPS. The PUCT defines such events as "weather-related damage, mechanical failure, lack of transmission capacity or availability, strikes, lockouts, actions of a governmental authority that adversely effect the generation, transmission, or distribution of renewable energy from an eligible resource under contract to a purchaser" but not failure of the spot or short-term market to supply renewables	Municipal power producers do not have a TRC requirement unless they open their markets to retail competition, but can sell TRCs to obligated LSEs	None
Wisconsin	Utilities in excess of their RPS requirement can apply to the PUC for TRCs that can be traded with other providers or banked to apply to subsequent RPS requirements. Unlimited banking is allowed Total retail sales determined by calculated a 3-year rolling average of LSE's retail sales	Fines of $5,000-$500,000 can be levied for non-compliance. Wisconsin PUC also has typically regulatory powers over regulated utilities	IOUs, municipalities and cooperatives are all subject to the RPS requirement; limited exemption given to certain providers	State has SBC find that is targeted at non-RPS eligible resources

Appendix 2. Portfolio Theory Basics.
Excerpted from Awerbuch, S. "Getting it Right: The Real Cost Impacts of a Renewable Portfolio Standard," Public Utilities Fortnightly, February 15, 2000.

Portfolio Theory: The Basic Ideas

Figure 1 shows the risk-reward tradeoff for a financial portfolio of two risky assets, A and B, which can be two common stocks (or groups of common stocks), or two groups of generating assets. Risk is defined as the standard deviation of the periodic (i.e., year-to-year or month-to-month) returns to the portfolio.8 Stock A (top right) is riskier; it has an expected return of 17 percent, coupled with a standard deviation of 0.41. Stock B offers lower return coupled with less risk; its expected return is just over 7 percent and its standard deviation is 0.27.

From a risk-reward perspective, it makes little sense to own only Stock B (or analogously, generating technology B), since there exist combinations of A and B that will produce superior results. In general, it makes no sense to own any portfolio combination that lies below portfolio V. For example, Portfolio R (consisting of 48 percent A plus 52 percent B) has the same standard deviation as Portfolio P (18 percent A plus 82 percent B) but produces a higher expected return. Investors seeking returns greater than those provided by V and R must accept greater risk by incorporating more Stock A into their mim This choice moves them along the risk reward curve to portfolios like S.

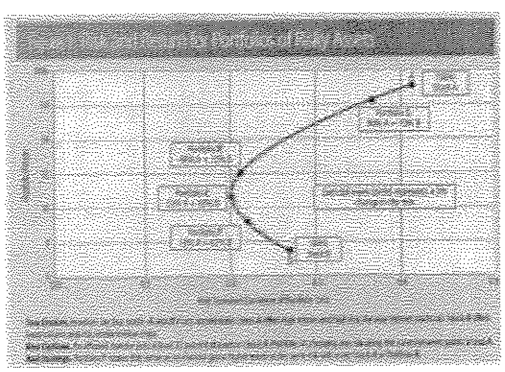

Figure 1:

Given the two risky assets A and B, it is not possible to prescribe a single optimal portfolio combination, only the range of efficient choices, i.e., those that lie on the risk return curve above V. Investors will choose a risk-return combination based on their own preferences and risk aversion. More risk-averse investors would be inclined to own relatively conservative portfolios such as V, while less risk averse individuals will operate at S or A.

The Riskless Asset: Diversification and Leverage

Adding a riskless asset to the A-B mix produces interesting and counterintuitive results. In financial portfolios, riskless assets generally consist of US. Treasury bills. The term "riskless" actually is misleading since even short-term Tbills bear some risk; e.g., their market value will fluctuate in response to changing interest rates. For this reason, T-bills are more properly called zero-beta assets, to distinguish that they are not truly free of risk, but are riskless when the returns are expressed in a particular manner.9 This section describes the remarkable effect that so-called "riskless" Treasuries have on the financial portfolio.

Figure 2 illustrates the effects of adding riskless T-bills (that yield 5 percent) to the previous mix of risky stocks A and B. The risk-reward curve for various combinations of A and B remains unchanged from Figure 1. The new element in Figure 2 is the straight line, which represents the risk return combinations for portfolios consisting of risky and riskless assets.10 Point M, the tangency point between the line and the curve, now becomes the optimal mix of risky assets (M consists of 60 percent A plus 40 percent B). The solid portion of the straight line gives the risk-return combinations for portfolios consisting of the mix M plus T-bills. For example, Portfolio H consists of 50 percent T-bills plus 50 percent of the portfolio M (i.e., 50 percent T-bills, 30 percent A and 20 percent B). As more T-bills are added, the risk/return point moves down the line (each tick mark represents a 25 percent change) until the portfolio consists of 100 percent Tbills and 0 percent M. At this point, its risk and return are 0.0 and 5 percent respectively, as shown in Figure 2.

DIVERSIFICATION. We now can more closely examine the powerful (and counterintuitive) impact that T-bills have on the portfolio. For example, portfolio H, which includes Tbills, has the same expected return as P (which does not), but is considerably less risky This example (Figure 2) illustrates that by including lower-yielding but riskless assets, we can create a portfolio that produces the same expected return-9 percent-but cuts risk nearly in half! Similarly, T-bills make it possible to move from portfolio V up to K, a move that raises return to 12 percent (from about 10.4 percent) without increasing risk.

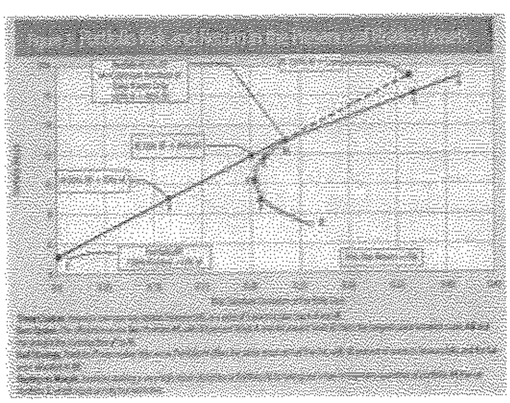

Figure 2:

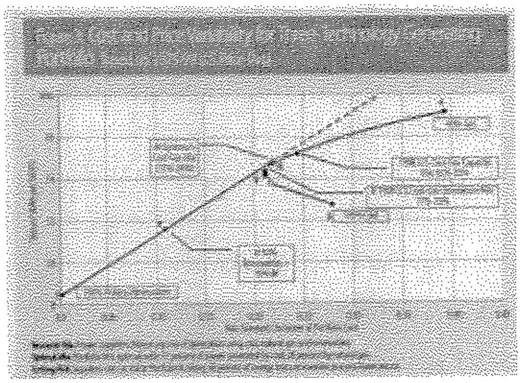
Figure 3:

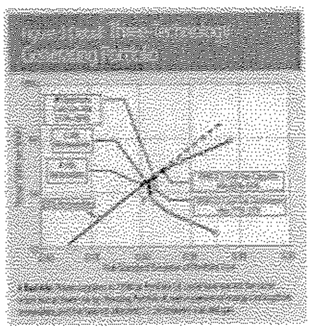
Figure 3

(The gain from such moves can be even more sizeable depending on the relative risks of A and B and the risk-free rate of return. That these moves are possible illustrates why M is the optimal mix of A and B.)

With riskless assets, investors seeking risk-return combinations below M can construct portfolios such as K and H (which use a mix of M plus T-bills) that are superior to mixes that include only risky assets. That means that by adding a mixture of, for example, risky Internet stocks and T-bills, the investor can improve the annual return from Portfolio V without increasing its volatility. This powerful result, which holds in spite of the fact that T-bills yield less than either blue-chips or Internet highflyers, has significant implications for generating portfolios, where the inclusion of riskless renewables similarly can reduce risk and/or cost.

LEVERAGE. The dotted portion of the straight line in Figure 2 represents the additional risk-return combinations available when margin borrowing is permitted.12 Recall that in Figure 1, the only option for raising return above M was to add more high-flyers to the mix, moving along the curve to points like S. Now, however, if an investor should want returns greater than M, she can borrow funds and use them to buy more of M, which would move her to points like N (consisting of 150 percent of M coupled with 50 percent margin borrowing).12 Clearly margin borrowing is the better way to go: Note that N is superior to S.

The implication for generating portfolios is as follows: Contractual fixed-price arrangements that are the financial equivalent of margin borrowing will improve overall performance.

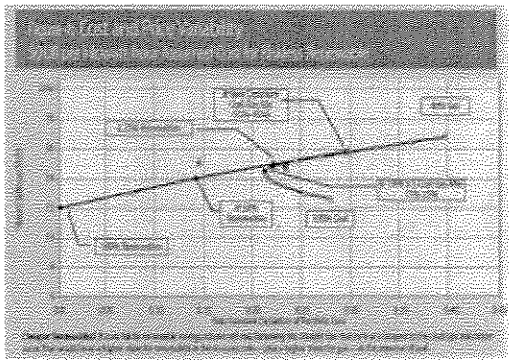

Figure 4:

To summarize, investors will adjust their risk return point to suit their preferences by adding riskless assets in Portfolio M or by using leverage. That means that all investors, independent of their risk preferences, will hold Portfolio M. This result has significant implications for national energy planning since it clearly implies that in the presence of riskless renewable resources, there exists a unique optimal mix of risky (fossil-based) alternatives that is independent of individual preferences and risk aversions.